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ORIGINAL PAPER - PRODUCTION ENGINEERING

Investigating the effect of heterogeneity on infill wells

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Abstract In recent years, improving oil recovery (IOR) has become an important subject for the petroleum industry. One IOR method is infill drilling, which improves hydrocarbon recovery from virgin zones of the reservoir. Determining the appropriate location for the infill wells is very challenging and greatly depends on different factors such as the reservoir heterogeneity. This study aims to investigate the effect of reservoir heterogeneity on the location of infill well. In order to characterize the effect of heterogeneity on infill well locations, some geostatistical methods, e.g., sequential gaussian simulation, have been applied to generate various heterogeneity models. In particular, different correlation ranges (R) were used to observe the effect of heterogeneity. Results revealed that an increase in correlation ranges will lead to (1) a higher field oil production total, and (2) a faster expansion of the drainage radius which consequently reduced the need for infill wells. The results of this study will help engineers to appropriately design infill drilling schemes.

Keywords IOR · Infill wells · Heterogeneity · SGS · Correlation ranges · Drainage radius

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Introduction

Infill drilling technique plays an important role in reservoir development especially in tight reservoirs. Increasing oil price and limitations of new reserves make improving oil recovery methods inevitable. As the recovery ratio is controlled by many complicated factors, such as the level of reservoir heterogeneity, determining the location of infill wells seems to be a very challenging issue (Soto et al. 1999). Hence there is no homogeneous reservoir in reality, and it is widely believed that in heterogeneous reservoirs infill drilling plays an important role (Hou and Zhang 2007; Barber et al. 1983) and improves oil recovery by accelerating productions (Driscoll 1974; Gould and Munoz 1982; Gould and Sarem 1989; Sayyafzadeh and Pourafshari 2010). Moreover, if infill drilling is linked to water flooding, it becomes more effective and economical comparing to chemical injection or tertiary recovery (Holm et al. 1980; French et al. 1991; Thakur and Satter 1998). The existence of different rock types with various thicknesses between two wells in a reservoir may cause a complex flow behavior. One of the applications of infill wells is to reduce the distance between the wells which helps maintain layer continuity and enhances well connectivity (Wu et al. 1989; Malik et al. 1993).

Making a precise decision on the location and number of infill wells is critical to the economics of an infill drilling project. Feasibility of infill drilling potential, especially in marginal fields, must be reliably assessed both technically and economically (Cheng et al. 2008). Therefore, it is highly recommended to conduct a complete reservoir evaluation consisting of geological, geophysical, and petrophysical reservoir analysis and interpretations to determine infill drilling potential in a reservoir. While this is a very accurate method, this approach can be

Table 1 Known permeability data in the reservoir model

Cell location	(32, 47)	(31, 26)	(27, 90)	(20, 12)	(15, 86)	(10, 32)	(6, 2)	(5, 30)	(2, 80)	(1, 5)
K (md)	208.812	107.974	32.9067	73.5827	262.615	198.433	176.104	91.4402	73.5827	151.29
Cell location	(93, 55)	(85, 47)	(81, 31)	(64, 44)	(62, 95)	(59, 29)	(51, 1)	(43, 22)	(39, 79)	(36, 67)
K (md)	187.548	262.615	228.224	91.4402	151.29	123.366	278.007	270.444	54.1704	151.29

prohibitively time consuming and expensive for hydrocarbon fields.

Methods of investigating infill well potential are divided into two main categories: (1) statistical methods and (2) optimization methods.

Statistical methods

A statistical view is the first approach in reservoir evaluation. The most common method in statistical approaches is the moving window technique. This method can use a minimum amount of reservoir geological description to determine the infill potential (Fuller et al. 1992). There have been a multitude of empirical and statistical analysis developments in the moving window method (Hudson et al. 2000, 2001). McCain et al. (1993) particularly used the statistical moving window approach to determine infill potential in a complex, low-permeability gas reservoir (McCain et al. 1993). Later, Voneiff and Cipolla (1996) developed the moving window technique and applied it for rapid assessment of infill and recompletion potential in the field (Voneiff and Cipolla 1996).

The other approach to find infill candidate wells is rapid inversion. In this technique, which was introduced and developed by Gao and McVay (2004), reservoir simulation is combined with automatic history matching (Gao and McVay 2004). In rapid inversion, a reservoir simulator serves as the formal method to calculate well production responses from reservoir description data. Then sensitivity coefficients are calculated internally and are used in the estimated permeability field and forward model. Lastly, the expected performances of potential infill wells can be determined (Guan et al. 2005).

Optimization method

Disseminating the locations of well is one critical issue in exploration and development of oil and gas fields. The process of determining the optimal well location is an optimization problem.

Table 2 Model parameters

Property	Explanation
Number of permeability data points	20
Reservoir dimensions	2500 × 2500 × 30 ft
Number of grids	100 × 100 × 1
Variogram type	Isotropic spherical
Uniform interval	625 ft
Minimum permeability	0 md
Maximum permeability	300 md
Number of simulation runs	100 times

Shook and Mitchell (2009) used time-of-flight to extend the derivation of classical measures of heterogeneity to three-dimensional models. They proposed application of flow-capacity/storage-capacity F-∅ diagram, Lorenz coefficient. Moyner et al. (2014) used flow diagnostics for reservoir management. They used Lorenz coefficient as the popular measure of heterogeneity in the context of streamline. Based on their work, the coefficient perfectly correlated with oil recovery predicted by a multiphase flow simulation. Also they used Lorenz coefficient as an objective function for optimization process (Moyner et al. 2014).

Although the Lorenz coefficient correlates well with recovery, it will generally give multiple local minimums and using from global optimization method will be necessary.

Several new methods are suggested by researchers, and only a few studies have presented a careful comparison of their performance with more popular genetic algorithm-based and gradient-based optimization techniques. (Onswnulu and Durlofski 2010; Nasrabadi et al. 2012).

Genetic algorithm

This method is one of the most popular methods in the well placement optimization. The idea of a genetic algorithm is first introduced by Holland in 1975 (Ariadji et al. 2014).

The genetic algorithm is a stochastic and heuristic search technique (Abukhamsin 2009). A genetic algorithm,

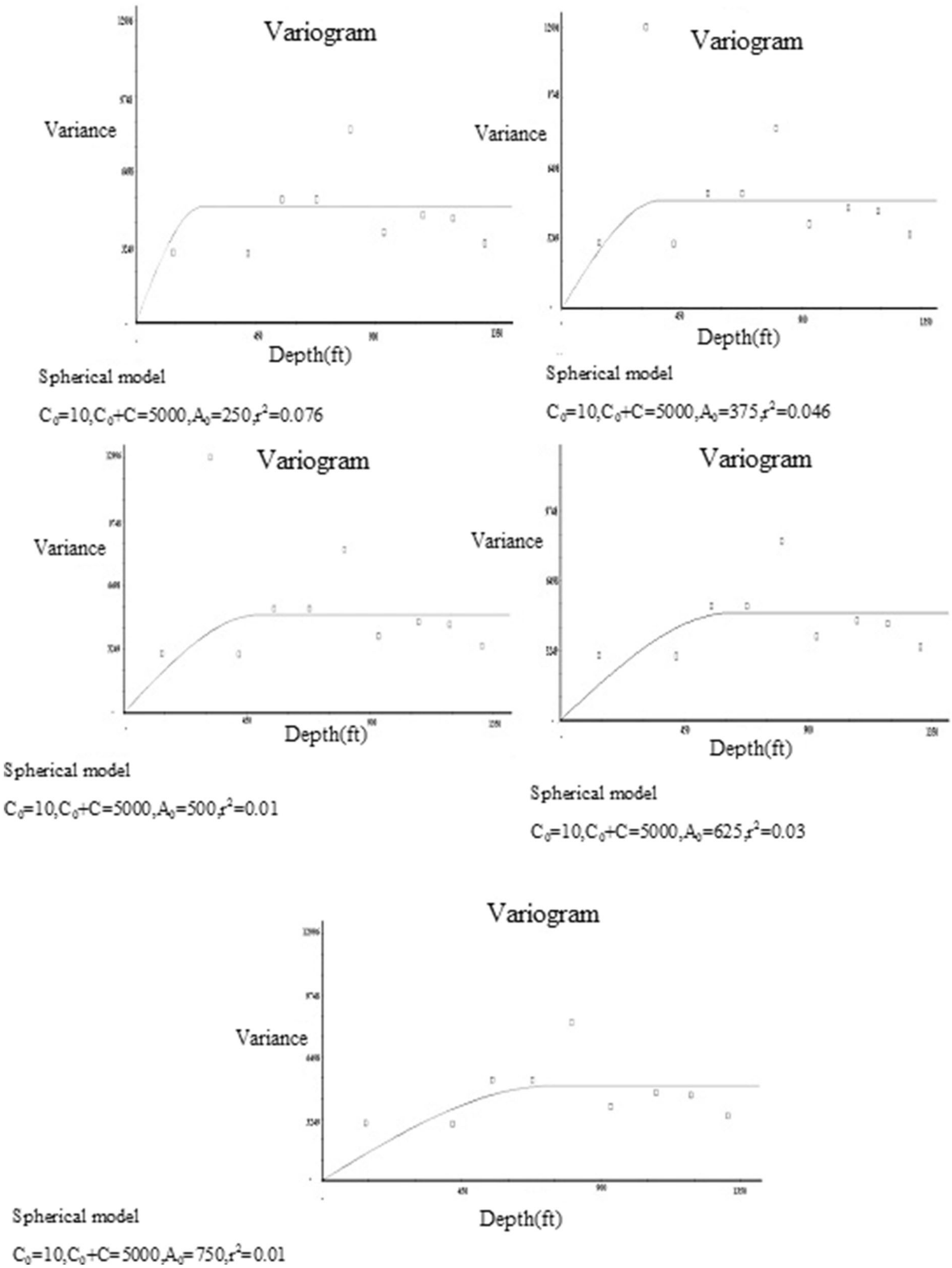

Fig. 1 Variogram models for different realizations

Table 3 Variogram model parameters

No.	Variogram type	Range (ft)	Sill	Nugget
1	Spherical	250	5000	10.0
2	Spherical	375	5000	10.0
3	Spherical	500	5000	10.0
4	Spherical	625	5000	10.0
5	Spherical	750	5000	10.0

in its purest form, will try to replicate the concepts of natural evolution, in a controlled and mathematical environment. In a well placement optimization problem, the different individuals in a generation are replaced with well location data, and their cumulative production or NPV is a measure of their chance of survival (Nasrabadi et al. 2012).

The first step in optimization of well placement by genetic algorithm is to generate an initial population (randomly selected well locations). The next step will be to evaluate each well and rate their individual performance by calling a reservoir objective function.

Gradient method

Gradient-based method is an important class of optimization methods. This method provides an improved objective function; each iteration results in a better well placement scenario, close to the original selection within a few iterations (Nasrabadi et al. 2012).

As the optimal location for a new well depends on how it is to be operated, Isebor et al. (2014) considered well location and well control optimization problems simultaneously as a joint problem and applied gradient approach in addition to several other methods to solve the optimization problem. They believed that exclusive gradient method may get trapped in relatively poor local optima (Isebor et al. 2014).

Current optimization methods do not include both reliability and efficiency features simultaneously. Although gradient-based methods are very efficient, they are highly dependent on the initial guess and cannot guarantee finding a global optimum. However, more reliable methods, such

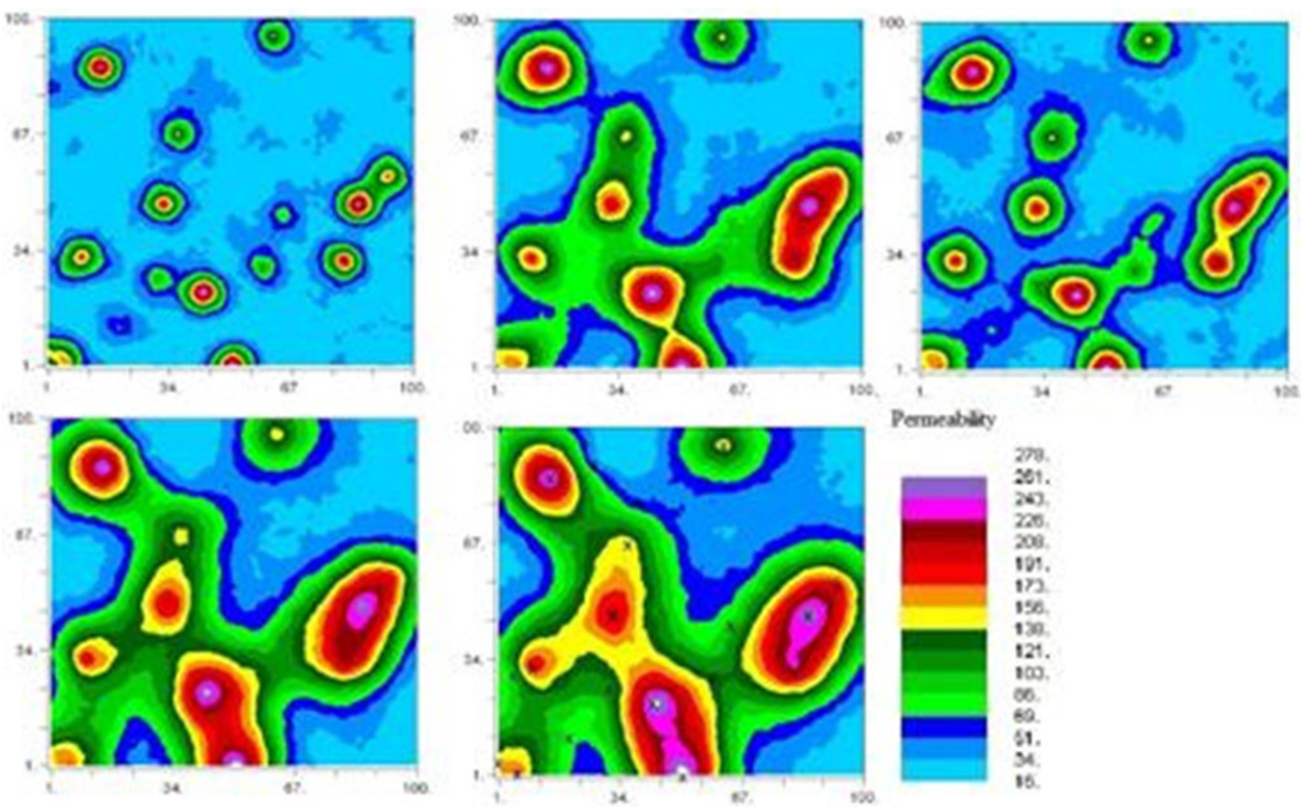

Fig. 2 Permeability model generated using the variogram of Fig. 1

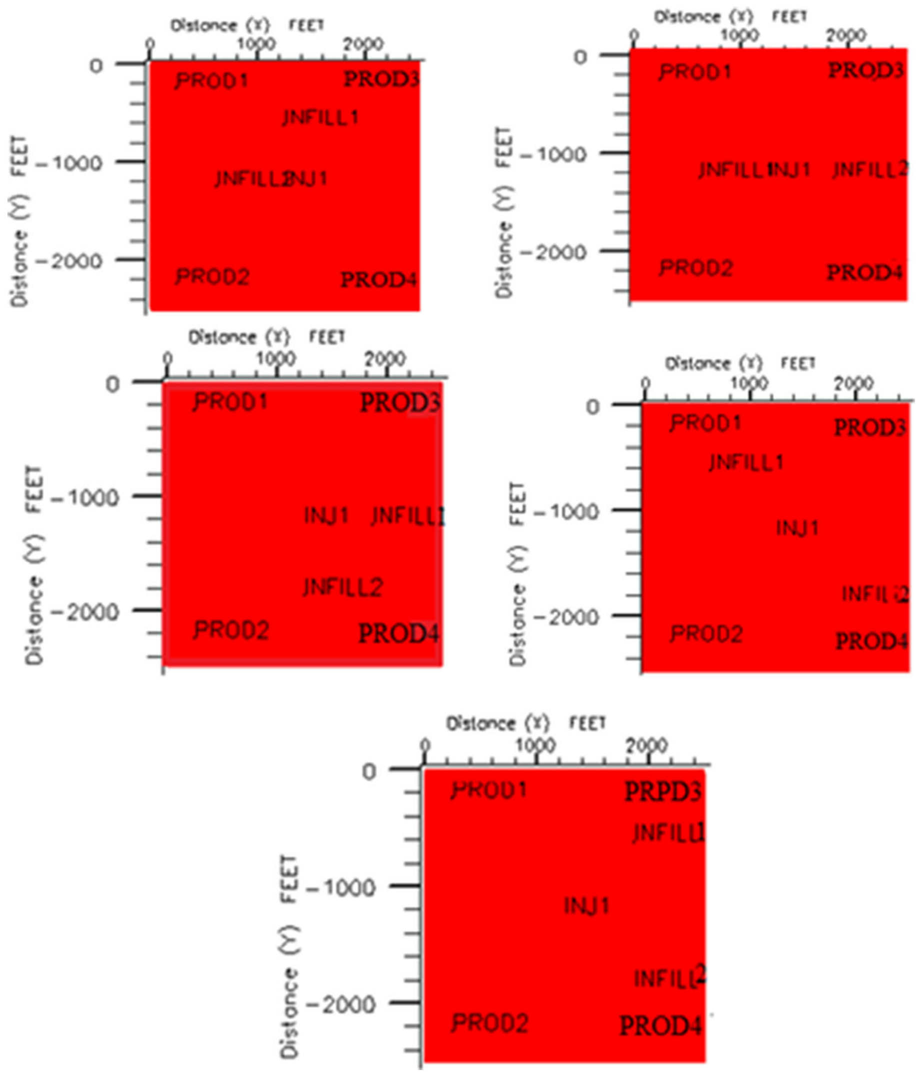

Fig. 3 5-spot well pattern and the selected infill wells between them

as genetic algorithm, need an excessive number of reservoir simulation which makes their field application very expensive (in terms of required CPU time or computational hardware).

In order to solve such problems, there are new and advanced methods. However, it should not cause neglecting basic methods. Although more advanced optimization-based techniques have been presented for well placement, this is a basic research attempting to find a relation between correlation lengths in permeable/impermeable region with well spacing within infill drilling decision. We used geostatistical method to investigate the effect of heterogeneity on infill wells.

Model set-up and procedure

The starting point in system behavior recognition is generating a static reservoir model. Generally, in simulation and modeling, the number of known parameters is less than

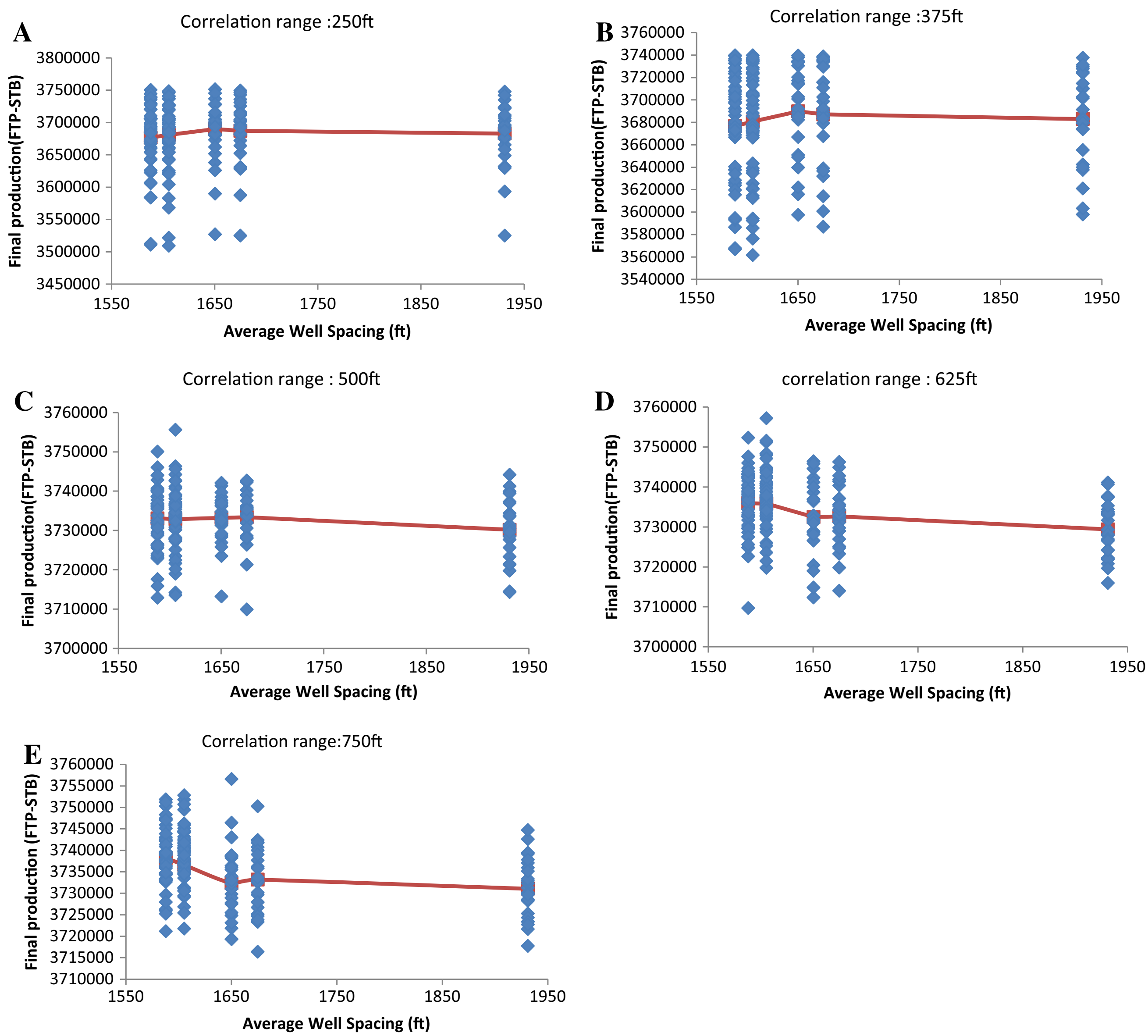

Fig. 4 Final production versus average well spacing for each correlation ranges (from diagram **a**–**e**): 250, 375, 500, 625, and 750 (ft)

that of the unknown ones. Therefore, applying a suitable estimation method for solving the problem is essential. In addition to all estimation techniques, simulations based on geostatistical methods, such as Sequential Gaussian simulation (SGS), seem to be very efficient. In the SGS method, different realizations can be produced from a data series with the same probability. This method is an appropriate technique for generating data with constant spatial variability of statistical parameters. In this study, after generating the heterogeneity factors with the SGS method, a 5-spot standard model has been applied for the basic wells' arrangement. Then heterogeneities in five different correlation ranges (drawn from the SGS model results) were applied in the basic model.

In particular, 20 permeability data points were used to generate the permeability model using geostatistical

Table 4 The reservoir characteristics

Reservoir characteristics	Explanation
Reservoir dimensions	$2500 \times 2500 \times 30$ ft^3
Reservoir depth	18,000 ft
Grid numbers	$100 \times 100 \times 1$
Grid dimensions	$25 \times 25 \times 30$ ft^3
Porosity	20 %
Reservoir rock type	Sandstone
Reservoir rock compressibility	1.2E−6 (1/psi)
Reference pressure	4100 psi
Initial reservoir pressure	3000 psi
Initial water saturation	20 %
Residual oil saturation	15 %
Oil density	37.457 lb/ft^3
Water density	62.366 lb/ft^3
Oil viscosity	1.174 (Cp)
Water viscosity	0.9 (Cp)

Table 5 Well characteristics

Well characteristics	Explanation
Water injection pressure	3000 psi
Production type	Constant rate
Production rate	2000 STB/day
Water cut limit	90 %
Simulation start day	30 Jan 2013
Simulation time	30 years

methods (Table 1). Therefore, in order to show the heterogeneity effect, five different correlation ranges of 250, 375, 500, 625, and 750 ft were applied in the variogram model construction. By means of SGS, 25 different realizations were produced to calculate the error of each correlation range. However, it should be noted that some assumptions were taken into account before generating the permeability models. For this research, a one-layer reservoir with 2500 ft $\times$ 2500 ft $\times$ 30 ft dimensions which consists of $100 \times 100 \times 1$ grids in the x, y, and z directions was applied. The reservoir rock type was normal sandstone with a constant porosity of 20 %, and the initial pressure of the reservoir rock was 2000 psi (Table 2).

Figure 1 illustrates the applied variograms in the reservoir modeling. The assumptions for the variogram model construction are given in Table 3.

An example of a permeability map generated using the variogram shown in Fig. 1 is plotted in Fig. 2.

In order to generate the permeability map, a 5-spot pattern is applied as the basic scenario on the reservoir which consists of four production wells and one injection well in the middle of the reservoir. Then, two infill

Table 6 Maximum production of every realization in different correlation ranges

Rx (ft)	1st real_FOPT(STB)	2nd real_FOPT(STB)	3rd real_FOPT(STB)	4th real_FOPT(STB)	5th real_FOPT(STB)	6th real_FOPT(STB)	7th real_FOPT(STB)
250	3,743,068	3,715,556	3,730,986	3,664,112	3,693,270	3,630,982	3,715,710
375	3,700,714	3,729,545	3,739,508	3,684,835	3,682,228	3,739,741	3,648,883
500	3,734,676	3,750,074	3,736,326	3,739,886	3,736,853	3,739,670	3,745,588
625	3,751,168	3,747,122	3,734,064	3,748,386	3,741,471	3,739,954	3,739,617
750	3,735,812	3,742,137	3,751,162	3,751,790	3,739,418	3,741,744	3,737,803

Rx (ft)	8th real_FOPT(STB)	9th real_FOPT(STB)	10th real_FOPT(STB)	11th real_FOPT(STB)	12th real_FOPT(STB)	13th real_FOPT(STB)	14th real_FOPT(STB)
250	3,704,360	3,701,810	3,652,314	3,682,523	3,682,138	3,637,732	3,746,240
375	3,692,330	3,734,210	3,714,133	3,621,897	3,735,034	3,717,181	3,737,894
500	3,746,318	3,742,579	3,738,566	3,723,530	3,728,330	3,741,262	3,742,706
625	3,733,829	3,745,974	3,733,079	3,745,815	3,757,206	3,747,996	3,732,520
750	3,736,808	3,737,370	3,736,158	3,747,025	3,748,263	3,745,852	3,756,550

Rx (ft)	15th real_FOPT(STB)	16th real_FOPT(STB)	17th real_FOPT(STB)	18th real_FOPT(STB)	19th real_FOPT(STB)	20th real_FOPT(STB)	21st real_FOPT(STB)
250	3,735,670	3,701,436	3,681,522	3,672,871	3,592,898	3,704,751	3,751,390
375	3,615,732	3,667,566	3,688,377	3,691,296	3,702,766	3,639,563	3,686,172
500	3,744,041	3,731,994	3,733,803	3,742,567	3,742,103	3,736,840	3,740,203
625	3,747,622	3,743,366	3,741,388	3,752,307	3,740,914	3,744,701	3,740,489
750	3,752,798	3,730,548	3,742,967	3,750,269	3,740,688	3,742,589	3,745,083

Rx (ft)	22nd real_FOPT(STB)	23rd real_FOPT(STB)	24th real_FOPT(STB)	25th real_FOPT(STB)	av.
250	3,696,103	3,727,988	3,711,507	3,526,629	3,688,143
375	3,597,721	3,650,738	3,715,582	3,730,524	3,690,567
500	3,738,521	3,742,318	3,755,599	3,740,703	3,739,802
625	3,743,050	3,746,392	3,744,878	3,742,300	3,743,424
750	3,737,631	3,750,222	3,738,868	3,751,795	3,743,654

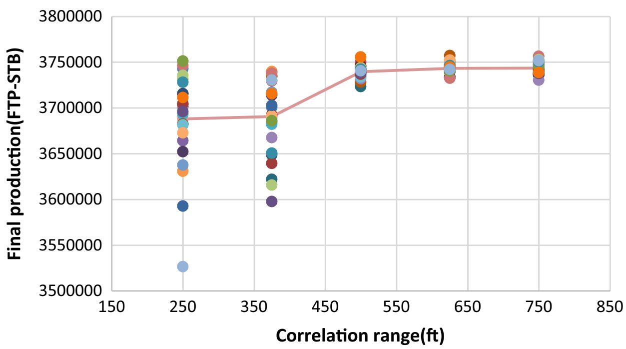

Fig. 5 Final production of reservoir versus correlation range

potentials were placed in the basic model at six different locations (Fig. 3). Each production well produces with the constant rate of 2000 bbl./day and the injection pressure is 3000 psi. The simulation was applied to this reservoir to predict the reservoir behavior for 40 years of production. Thereafter, 100 realization simulations took place for each well configuration, and the average of these 100 simulations was considered for each correlation range. Finally, total production of each case was compared to the average well spacing for each infill pattern as shown in Fig. 4. Also, characterization of production reservoir mentioned in Tables 4, 5.

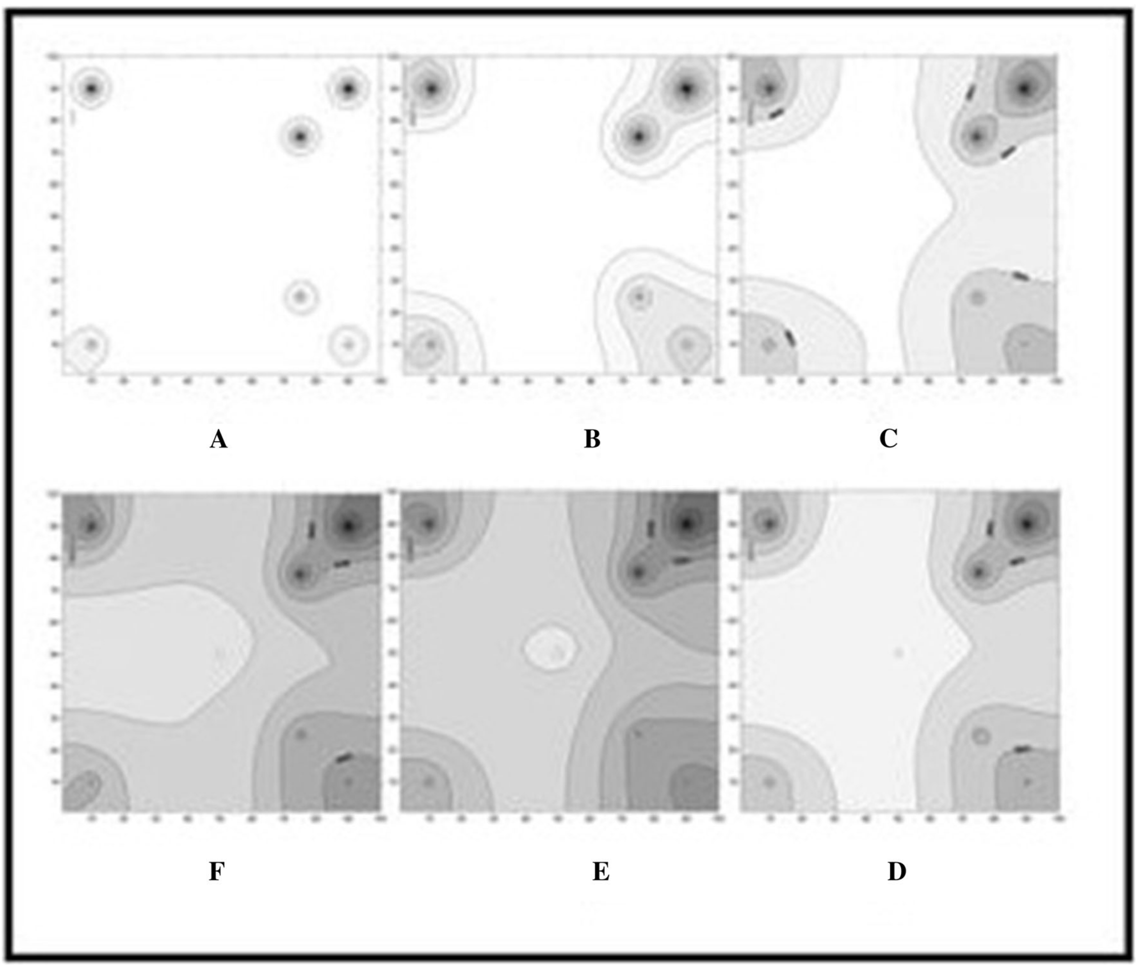

Fig. 6 Drainage radius after the first 10 days for the model (with correlation range of 625 ft)

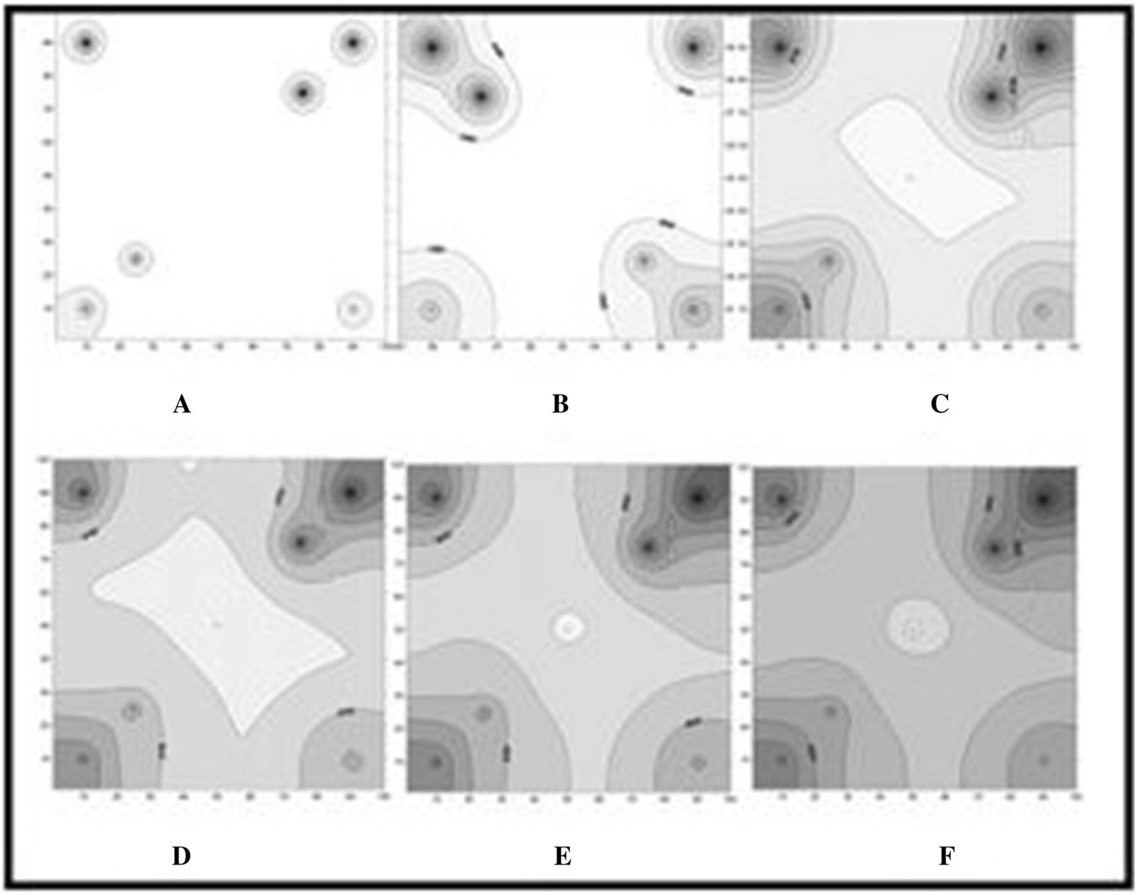

Fig. 7 Drainage radius after the first 10 days for the model (with correlation range of 500 ft)

Table 7 Drainage radius in every correlation range

	Rx 250	Rx 375	Rx 500	Rx 625	Rx 750
Day 1	443.807	443.425	425.268	450.115	456.804
Day 2	705.275	715.596	721.33	791.284	1026.38
Day 4	850.057	920.298	1014.91	1204.13	1384.75
Day 6	951.835	1192.66	1324.54	1390.48	1390.48
Day 8	1069.38	1364.68	1376.15	1390.48	1390.48
Day 10	1189.79	1384.75	1384.75	1390.48	1390.48
Day 12	1227.06	1384.75	1384.75	1390.48	1390.48
Day 14	1235.67	1384.75	1384.75	1390.48	1390.48
Day 16	1390.48	1390.48	1390.48	1390.48	1390.48
Day 18	1390.48	1390.48	1390.48	1390.48	1390.48

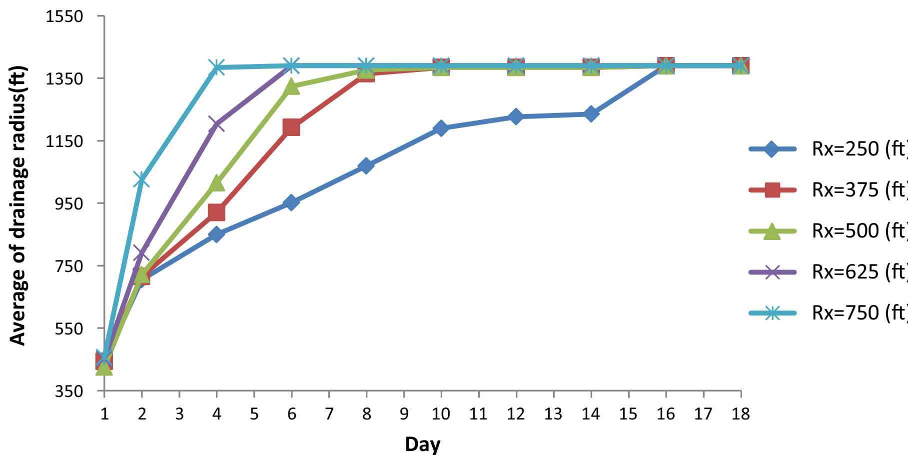

Fig. 8 Changes of average drainage radius in different correlation ranges versus time

According to Fig. 4, reducing the average well spacing in an infill drilling scenario causes an increase in total production. However, if this average distance becomes less than 1500 ft, it will have a reverse effect and the total production will decrease. It should be mentioned that for higher correlation ranges more production in the reservoir occurs with less average well spacing. Moreover, changes in correlation ranges also may affect production values. The maximum production value in each realization and at each correlation range is summarized in Table 6.

Figure 5 illustrates that while the correlation range increases, hydrocarbon production will increase as well. Also, in lower correlation ranges, there are more scattered data than those observed at higher correlation ranges. This may be caused by higher correlation ranges leading to a greater effective radius in the simulation outcomes. Therefore, the reservoir will be more homogeneous, and, as a result, the production rate from the reservoir will increase.

In order to observe the changes in the well drainage radius, the pressures of each cell were calculated, and the isobar surfaces were plotted at different time steps. The graphs reveal that the pressure diminished through the production period (Figs. 6, 7; Table 7).

It can be concluded from the graphs seen in Fig. 8 that it takes more time for the drainage radius to reach its maximum level in lower correlation ranges. This means that by increasing the correlation ranges, the heterogeneous reservoir can be assumed to be a homogeneous one (see Fig. 9).

Conclusions

In this research, the effect of reservoir heterogeneities generated by geostatistical methods applied to infill drilling scenarios has been discussed. The following can be concluded from this study:

1. Infill drilling is an appropriate method in developing hydrocarbon reservoirs and producing more oils.
2. Increasing the correlation range may cause an increase in the production of the reservoir. The production increased almost 59–61 % in the first 10 years and 11–15 % at the end of the simulation. In addition, the maximum drainage radius increased as well.
3. In infill drilling, reducing the average distance between wells to a certain limit resulted in an increase in the total production rate of the reservoir, but while the average distance between wells became less than 1500 ft, the final production decreased.

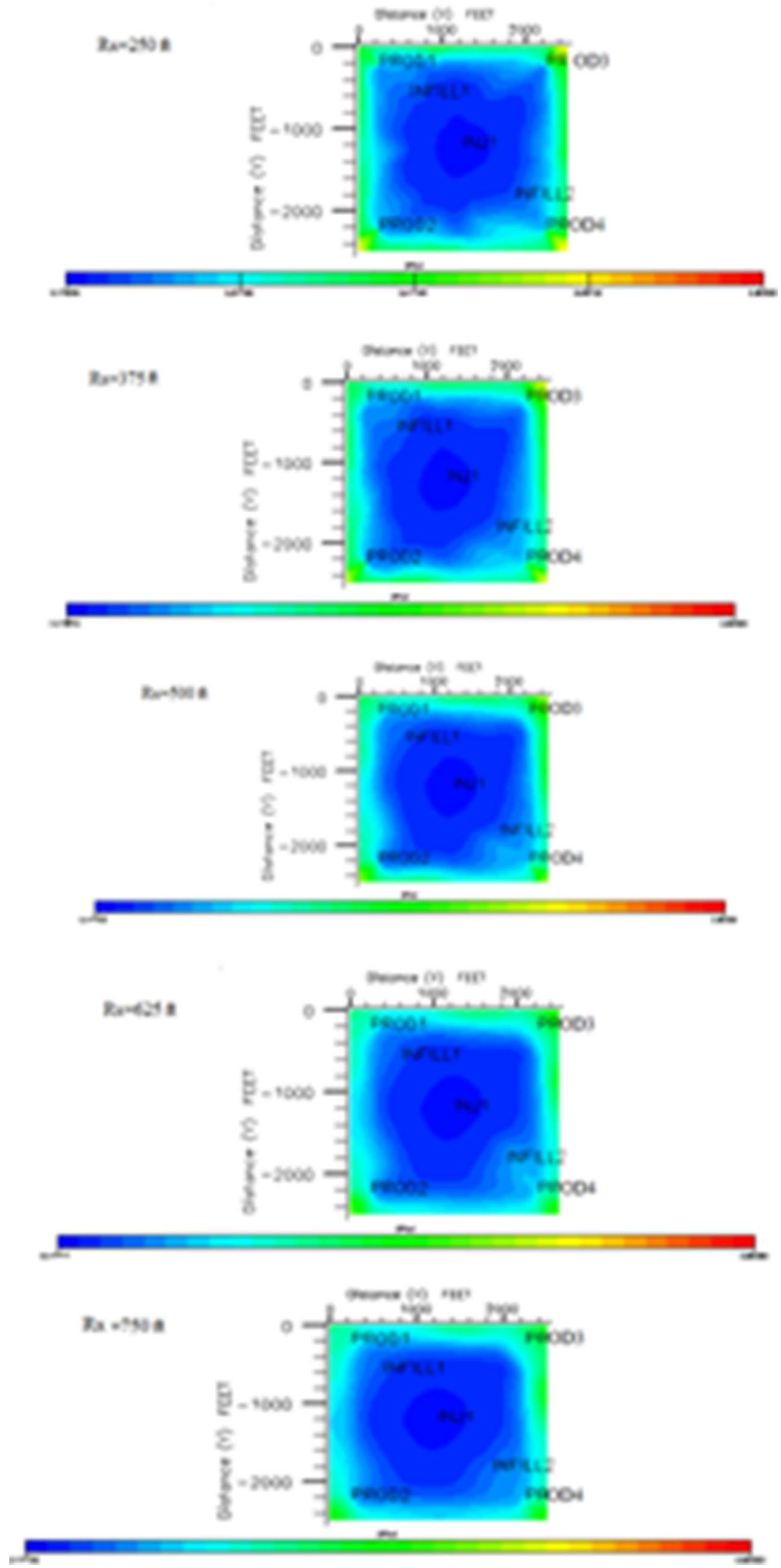

Fig. 9 Final oil saturation distribution after 40 years (end of simulation) for each correlation range

The results of this study can help engineers to better design appropriate infill drilling schemes.

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